

Supplementary Material

Energy system transition pathways to meet the global electricity demand for ambitious climate targets and cost competitiveness

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This supplementary materials document includes supporting information regarding the main article plus additional description of the input data, assumptions and used model. Further complementary figures and tables are also provided to give a more detailed overview of the findings in this research.

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Note S1. Literature review of employing high shares of renewable energy (RE) in global energy scenarios

There are various studies focusing on scenarios with high penetration of RE in the next decades. The target year for most of the scenarios is 2050, as also agreed by 197 countries to reach climate neutrality and limiting global temperature raise to well below 2°C, or more ambitiously 1.5°C, by 2050 [1]. However, only a few studies have been carried out in view of a high RE system globally. Global 100% RE or near 100% RE scenarios are briefly highlighted in the following, except the ones of Teske/DLR et al. and the team of Breyer et al., as they are described in more detail in the main article.

Sørensen [2] initiated a 100% RE system by developing four scenarios for 6 regions globally for the year 2050. Back in 1996, the author assumed that the future citizens in 2050 are risk takers, can adopt to the new ideas promptly and courageous to deal with negative impacts before they become vivid. Additionally, very progressive assumptions concerning economic and social developments were invoked. The considered scenarios are i) the clean fossil scenario with the idea of fossil fuels with carbon capture and storage (CCS); ii) the safe nuclear scenario with caution towards proliferation concerns, nuclear accidents and nuclear waste management; iii) the decentralised RE scenario using solar thermal, wind, biogas and solar PV as the main technologies while taking advantage of fuel cells, liquid biofuels such as methanol, heat pumps and a few energy storage options; iv) the centralised RE scenario is similar to the previous scenario but with lesser bioenergy and higher solar PV contribution plus intercontinental power transmission. The clean fossil and decentralised RE scenarios were detected to be technically and economically feasible.

Pursiheimo et al. [3] studied the impact of sectoral integration on global energy systems with a high share of RE under four different scenarios, from 2010 to 2050 in 10 year intervals. The adopted model for this analysis is called VTT-TIMES. The main driver for such a highly RE-based system is found to be solar PV contributing to 75% of electricity generation worldwide. However, limitation related to modelling high temporal resolution with time slices, and time-dependent demand, was identified as a main barrier to optimise variable RE and energy storage.

Jacobson et al. [4] studied the global energy system roadmaps for 139 countries powered by wind, water and sunlight (WWS), and later on explored matching supply with demand over shorter time scales among 20 world regions [5]. The findings of the latter research suggest that capital, consumption and social costs of the WWS scenario is significantly less than that in the

Business-As-Usual (BAU) scenario for the 2050-2054 power demand. The two main models used for this study are the GATOR-GCMOM and the LOADMATCH grid integration. In addition, a more recent study [6] for 143 countries in the world, that is aggregated to 24 regions for grid stability analyses, was developed to meet the future global energy demand through 80% and 100% RE no later than 2030 and 2050, respectively. Matching supply and demand were conducted for the years 2050-2052 in every 30 seconds. The main outcomes of this research are a massive reduction of social costs in the WWS compared to BAU by 91% in 2050, less end-use energy requirements, more jobs creation and lower air-pollution and global warming.

Löffler et al. [7] model defossilisation scenarios for the global energy system using the GENeSYS-MOD model, based on an earlier version of the OSeMOSYS model, for 10 world regions from 2015 to 2050 in 5-year intervals. The results reveal that the 1.5-2.0 °C climate target can be achieved, while respecting the CO₂ budget, by a combination of RE sources, dominated by wind energy and solar PV, that offer the least-cost solution.

Deng et al. [8] analysed the possible transition to a sustainable energy system for all energy sectors sourced 95% by renewables, where the total energy demand decreases and the electrification rate increases due to gain in energy efficiency. The energy transition is carried out from 2000 to 2050 in an annual resolution for every 10-year time steps using the Ecofys model.

Sgouridis et al. [9] explore energy transition pathways for large shares of RE, about 98%, until 2100. The possible trajectories range from the easiest to the hardest paths and the adopted model is named NETSET. A high acceleration in the RE investment is found crucial and using the most updated cost assumptions is argued to make the future energy system more realistic.

Luderer et al. [10] developed a first scenario based on an integrated assessment model (IAM) that consists of both energy-economy-climate system and land-use mitigation options aiming for high electrification and deep decarbonisation of the future energy systems. This is the only IAM research until today that is not biased toward over-utilisation of the combination of nuclear energy, bioenergy, CCS and carbon dioxide removal (CDR) in its scenarios. The analysis is carried out under six scenarios and 12 sub-regions using the REMIND-MAGPIE model, which is the combination of IAM REMIND and MAGPIE models, for the time horizon of 2020-2100. The results suggested for substantial renewables-based electrification that is

cantered by solar, wind and battery technologies and limited by nuclear energy, biomass, CCS and CDR options.

A thorough and tabulated data has been presented by Hansen et al. [11], Breyer and Jefferson [12] and Breyer et al. [13,14] for all the global energy system studies based on a massive implementation of RE integration. There are other energy system models that can be taken for designing an energy transition pathway but they have not been scaled up or tested on a global level, such as PyPSA [15,16] and EnergyPLAN [17].

The abovementioned global energy scenarios are not included in the current study due to:

- lack of transition description and limited to overnight system description only, as for Jacobson et al. [5,6] and Sørensen [2];
- lack of access to the high resolution and detailed data, as for Luderer et al. [ref], Pursiheimo et al. [3], Löffler et al. [7], Sgouridis et al. [9], Deng et al. [8];
- lack of global scenarios, as for the model PyPSA and EnergyPLAN;
- while also methodological issues or difference in approaches limit the applicability of the detailed LUT-ESTM for other scenarios.

Nevertheless, future research would strongly benefit from including comprehensive scenario comparisons of other research groups perhaps under a different regional scale or approach, as part of the future evaluation of energy systems models.

Note S2. Proxies used for distribution of regional data

Since data are not just provided for the electricity sector, but all energy sectors in the IEA and Teske/DLR scenarios, some modifications and assumptions are applied to estimate the projected capacity, generation and demand. Meanwhile, regional definition and grouping varies across different global studies, therefore, some modifications are needed to harmonise regional data resolution. Current power plant capacities are employed to calculate the total share of existing and projected power capacities for countries that have to be merged to or split from a region. Electricity consumption of countries as of today are considered as proxy for distribution of existing and projected electricity generation data from one region to another where necessary. However, both proxies show an almost similar ratio for the Teske/DLR scenarios, thus electricity consumption is chosen as the main indicator for data distribution. There have been some cases where the share of electricity consumption could not be directly applied to estimate the electricity generation in a region due to inconsistent capacities of power generators, unreasonable capacity factors, or power capacities decommissioned before reaching the technical lifetime. Therefore, an approximation is considered according to the current knowledge of the energy system in the region and expected capacity addition or projected electricity generation from an energy resource in the future. All the technical and financial assumptions have been adopted from the LUT research group and applied to all the scenarios for consistency, as shown in Table S3.

Global weather data for the year 2005 is taken from NASA database [18,19] and reprocessed by the German Aerospace Centre [20] for calculating the capacity factors for solar PV, CSP, and wind power. Capacity factors for single-axis tracking PV are computed based on Afanasyeva et al. [21]. The feed-in profiles for hydropower are calculated according to the monthly resolved river flow data for 2005 [22] as a normalised weighed average flow in locations of existing hydropower plants. The hourly values have been first calculated based on a spatial aggregation method described in Bogdanov and Breyer [23] and applied for 145 regions [24]. Using 145 regional profiles for the variable renewable resources decreases the effect of geographical time differences and the impact of different climate zone within one large region. However, higher resolution of data and regional subdivision can help reduce the abovementioned impact even further and reflect the real-world situation better. Hourly profiles for the 145 regions in the world are weighted using the installed capacity of the respective regions in 2050, taken from Bogdanov et al. [24]. The year 2050 has been chosen because the electricity system is based on 100% RE and there is at least a small amount of renewable

capacities available for the technologies. There have been some cases where there is no CSP capacities for the entire region by 2050, thus the existing capacities for the year 2015 have been applied. Regarding offshore wind, the LUT database only includes a high-resolution hourly profile for Europe. For other regions, the full load hours (FLH) of offshore wind have been obtained from Teske's supplementary data [25] and applied to the LUT onshore wind hourly profiles. To generate the load profiles, available load profiles for the 145 LUT regions have been weighted using the electricity demand projection. The main source for all the data used as proxy in this research is Bogdanov et al. [24].

For the Teske/DLR and International Energy Agency (IEA) scenarios, the FLH given in the respective sources are used and profiles have been scaled up or down accordingly. The main sources of the input data for all the analysed scenarios are Bogdanov et al. [24], Teske et al. [25], and IEA World Energy Outlook (WEO) 2017 and 2020 [26,27]. All data for the years 2015 and 2020 have been set as the current energy system for all scenarios uniformly.

Note S3. Electricity demand projection and load profile

One of the key input data for every energy system analysis is the demand estimate for the future. There are several factors that can be considered for such projections. The IEA demand trajectories are made based on macroeconomic and demographic assumptions such as population growth, gross domestic product (GDP) and economic development for each region [28]. For the LUT regions, the projection of electricity consumption has been carried out using the IEA-STEPS estimate [26,29]. Since this scenario includes a very low or almost negligible rate of electrification in the heat and transport sectors, the provided growth rate is practically a forecast for increase in electricity consumption in the electricity sector of the today's structure for the future. Teske [25] proposes a bottom-up approach with regards to the increase in electricity consumption for the heat and transport sectors as well as production of e-fuels and hydrogen. The EM model of DLR is used for the long-term projection of the annual electricity demand, and the [R]E 24/7 model of UTS (University of Technology Sydney) divides the major regions into smaller clusters (up to 8 clusters) to calculate hourly load profiles and generation time series. Regarding the electricity system, all the studies claimed that hourly demand profiles have been employed. However, the IEA uses load profiles for each energy sector and subsector, such as residential, industry and transport, for every 24 hours of 36 typical days. The aggregated electricity demand of each sector is then matched to the total load profile of a given country. There are four segments in the WEM to meet the annual demand, including baseload demand, low midload demand, high midload demand and peakload demand. To integrate variable renewables, the probable contribution of RE in each of the four segments is calculated by the model and then subtracted in the merit order from the segments. Eventually, dispatchable generators meet the residual load-duration curve that is left after accounting for electricity generation from RE. For consistency, uniform hourly load profiles have been used for all the scenarios, taken from Toktarova et al. [30]. To generate the load profiles, available load profiles for the 145 LUT regions have been weighted using the electricity demand projection. The main source for all the data used as proxy in this research is Bogdanov et al. [24].

Final electricity consumption data for all the major regions and scenarios are shown in Table S1. The electricity consumption in the first two years is identical for all the scenarios and taken from Ref. [24] for the year 2015. Electricity consumption for the year 2020 is estimated using the ratio of electricity consumption to generation according to the LUT-ESTM that is multiplied to the electricity generation in 2018 taken from the WEO 2019 report [31]. At the time of data processing, the 2019 version of the report was the latest of this series of

publications and the 2018 data was the closest data to be used for 2020. Nonetheless, given data in the most recent IEA publication for 2020 is noted as an estimate as well. Moreover, the projected data for the IEA scenarios are adopted from the WEO 2020. As a result of using estimated data for the year 2020, there might be some cases where the electricity consumption experiences a slight decrease in 2025 and a growth right after from 2030 onwards. In the LUT scenarios, the final electricity consumption is kept the same for all the scenarios and the impact of efficiency improvements or demand-side management are not factored in. The current rate of electricity consumption growth is assumed to continue, and the projections are conducted according to the CAGR in the IEA-STEPS scenarios. To calculate electricity consumption for the electricity sector in the IEA scenarios, the total electricity generation provided in the IEA report is taken as a basis and the respective CAGR is calculated for every 5-year time step. For Teske/DLR scenarios, electricity consumption data for the major regions are taken directly from the publication without any further adjustments. It should be noted that the transmission and distribution grid loss projections are accounted for in the total electricity demand calculation and they are taken from Ref. [32].

Table S1. Final electricity consumption development throughout the transition from 2015 to 2050 in 5-year intervals (TWh). Abbreviations: Middle East and North Africa (MENA), Northeast Asia (NE-Asia), Southeast Asia and the Pacific Rim (SE-Asia), South Asian Association for Regional Cooperation (SAARC), sub-Saharan Africa (SSA), North America (N-Am), and South America (S-Am).

IEA - STEPS								
Regions	2015	2020	2025	2030	2035	2040	2045	2050
Europe	3,718	3,902	3,853	4,016	4,247	4,479	4,710	4,942
Eurasia	982	1,246	1,355	1,430	1,521	1,612	1,703	1,793
MENA	1,200	1,349	1,505	1,772	2,107	2,442	2,777	3,112
SSA	418	434	486	598	742	887	1,031	1,176
SAARC	1,356	1,513	1,769	2,255	2,865	3,474	4,084	4,694
NE-Asia	6,311	8,405	10,036	11,121	12,198	13,275	14,352	15,429
SE-Asia	1,104	1,327	1,740	2,071	2,426	2,780	3,135	3,490
N-Am	4,963	5,102	5,162	5,297	5,493	5,689	5,885	6,082
S-Am	1,015	1,137	1,282	1,449	1,668	1,886	2,105	2,324
Global	21,067	24,416	27,188	30,008	33,266	36,524	39,783	43,041
IEA - SDS								

Regions	2015	2020	2025	2030	2035	2040	2045	2050
Europe	3,718	3,902	3,906	4,215	4,747	5,278	5,788	6,339
Eurasia	982	1,246	1,315	1,329	1,352	1,374	1,423	1,479
MENA	1,200	1,349	1,442	1,728	2,128	2,528	2,923	3,343
SSA	418	434	511	650	808	966	1,182	1,429
SAARC	1,356	1,513	1,741	2,166	2,699	3,232	3,765	4,297
NE-Asia	6,311	8,405	9,731	10,454	11,323	12,192	13,062	13,931
SE-Asia	1,104	1,327	1,682	1,939	2,261	2,584	2,906	3,229
N-Am	4,963	5,102	4,885	4,915	5,165	5,415	5,888	6,514
S-Am	1,015	1,137	1,234	1,368	1,569	1,769	1,971	2,173
Global	21,067	24,416	26,447	28,766	32,052	35,338	38,907	42,734
Teske/DLR – 2.0°C								
Regions	2015	2020	2025	2030	2035	2040	2045	2050
Europe	3,718	3,902	3,719	4,107	4,381	4,656	4,691	4,726
Eurasia	982	1,246	1,139	1,303	1,494	1,685	1,701	1,716
MENA	1,200	1,349	1,582	2,034	2,504	2,975	3,577	4,179
SSA	418	434	565	760	1,104	1,448	1,948	2,447
SAARC	1,356	1,513	2,375	3,208	4,261	5,315	6,069	6,824
NE-Asia	6,311	8,405	8,195	9,259	10,104	10,950	10,896	10,842
SE-Asia	1,104	1,327	1,626	2,172	2,628	3,084	3,479	3,875
N-Am	4,963	5,102	5,095	5,517	5,710	5,902	5,788	5,673
S-Am	1,015	1,137	1,407	1,680	1,961	2,241	2,416	2,590
Global	21,067	24,416	25,703	30,040	34,148	38,255	40,564	42,872
Teske/DLR – 1.5°C								
Regions	2015	2020	2025	2030	2035	2040	2045	2050
Europe	3,718	3,902	3,646	3,998	4,235	4,472	4,453	4,434
Eurasia	982	1,246	1,100	1,237	1,394	1,552	1,574	1,595
MENA	1,200	1,349	1,583	2,065	2,585	3,105	3,700	4,295
SSA	418	434	601	848	1,246	1,643	2,234	2,825
SAARC	1,356	1,513	2,389	3,383	4,369	5,355	5,848	6,342
NE-Asia	6,311	8,405	8,258	9,380	9,753	10,125	10,173	10,221
SE-Asia	1,104	1,327	1,614	2,090	2,528	2,966	3,291	3,615
N-Am	4,963	5,102	4,938	4,846	4,944	5,041	5,225	5,409

S-Am	1,015	1,137	1,438	1,778	2,150	2,521	2,748	2,974
Global	21,067	24,416	25,567	29,625	33,203	36,780	39,246	41,711
LUT – BPS								
Regions	2015	2020	2025	2030	2035	2040	2045	2050
Europe	3,718	3,902	4,073	4,197	4,349	4,536	4,716	4,903
Eurasia	982	1,246	1,365	1,434	1,505	1,600	1,691	1,786
MENA	1,200	1,349	1,563	1,883	2,262	2,650	3,143	3,727
SSA	418	434	529	643	784	951	1,156	1,406
SAARC	1,356	1,513	2,129	2,708	3,356	4,040	4,935	6,028
NE-Asia	6,311	8,405	10,229	11,378	12,421	13,354	14,467	15,673
SE-Asia	1,104	1,327	1,704	2,016	2,353	2,716	3,153	3,660
N-Am	4,963	5,102	5,276	5,431	5,633	5,898	6,146	6,405
S-Am	1,015	1,137	1,337	1,505	1,695	1,908	2,149	2,420
Global	21,067	24,416	28,206	31,195	34,358	37,653	41,556	46,008

Note S4. Further description of the selected scenarios

LUT-BPS scenarios

Five scenarios have been designed and introduced for the first time under the Best Policy Scenario (BPS) category using the LUT-ESTM. These scenarios aim to achieve a zero CO₂ emissions target by 2050 or earlier, depending on the scenario. They are built on a 100% RE-based electricity system with no addition of nuclear power and fossil fuels with or without carbon capture and storage (CCS). Additional capacities for gas turbines or engines are allowed, while a fuel switch to non-fossil fuels is assumed in the scenarios. The current nuclear capacity is kept in the system until the end of its technical lifetime due to technical and financial reasons, resulting in a tiny fraction (<1%) of nuclear capacity running throughout the transition. A constant capacity factor (CF) of 0.85 is assumed for nuclear power from 2025 to 2050. This is because nuclear power has a comparably low operational cost but high capital cost. Therefore, once a nuclear plant is built, it is best to run it continuously. At the same time, nuclear power has a limited ramping capability [33]. The difference between the BPS – Wind Force (BPS-WF) and the BPS – No Wind Force (BPS-NWF) is that the wind power capacity can be repowered once installed and reached its technical lifetime. This means that the wind installed capacity of the previous year is the lower limit for the next year. Whereas, in the BPS-NWF scenario, there is no constraint for repowering the wind power capacity and the selection of technologies is based solely on cost-optimisation. The key elements of each BPS scenario are shown in Table 2 of the main manuscript. Further description of BPS scenario design can be found in Bogdanov et al. [24]. Two exemplary scenarios from the IEA and Teske/DLR have been selected and included in this analysis.

IEA scenarios

The IEA has recently published a new scenario so-called the Net Zero Emissions scenario by 2050 [34,35], which only includes the global data and regional data has not been provided yet. Thus, this scenario is not included in the current study, as essential data for reproducing are missing.

The STEPS is considered as the Business-As-Usual scenario since the scenario follows the current status of the energy sector while taking into account all the ongoing and planned government's policies and regulations for the future. It is clearly stated that this scenario fails to deliver full access to clean and affordable energy for all (e.g., 660 million people with no access to electricity) or to contribute in greenhouse gas (GHG) emissions reductions. The

amount of CO₂ emissions increases to 36 Gt by 2030, which violates the United Nations Sustainable Development Goals (UN SDG) and Paris Agreement substantially. Thus, the STEPS may be interpreted as a failed policy scenario.

The SDS have been the ambitious climate scenarios of the IEA reports for several years, which focuses on achieving the UN SDG that is most closely related to energy: affordable, reliable, sustainable and modern energy for all (SDG 7); reducing impacts of air pollution (part of SDG 3 and SDG 11); and tackling climate change (SDG 13). This scenario aims to reduce the global consumption of oil and coal, whereas the fossil methane consumption increases but with lower compound annual growth rate (CAGR) than that in the STEPS. More integration of RE, nuclear power and fossil CCS is another feature of this scenario. It is argued that the emissions in the IEA-SDS go down to zero eventually by 2070 using a wide range of technologies and measures such as repurposing the coal-fired power plants as a flexibility provider instead of one of the main electricity generators, equipping the existing fossil fuels power plants with CCS, or retiring the plants earlier than their technical lifetime (stranded assets).

In the IEA scenarios, it is assumed that fossil-fired power plants will be equipped with carbon capture and storage (CCS) throughout the transition. Although it is not clearly mentioned in the report, it seems that a fraction of fossil fuels with CCS would remain in the system even by 2070, hoping for capturing CO₂ before it releases to the atmosphere via carbon capture units at the point sources. The captured CO₂ is supposed to be transported and stored in an underground geological formation for centuries [36]. Conversely, the IEA documented that the process just includes the carbon capture units and cost of CO₂ transportation and storage is not taken into account (see [37], page 48). To reflect the full cost of fossil fuels with CCS, an additional cost of CO₂ transportation and storage has been considered. The transportation and storage cost is estimated to be in the range of 45 €/tCO₂ as the current cost up to 2030 and 30 €/tCO₂ by 2050 [38]. The cost for the remaining years has been interpolated and presented in Table S2.

Teske/DLR scenarios

The 2.0°C scenario is designed to reduce the GHG emissions to zero by 2050 [25,39], which has some similarities to the Advanced E[R] scenario published by Teske et al. in 2015 [40,41]. This scenario allows for some delays in GHG emissions reduction and deployment of RE due to socio-political issues.

The 1.5°C scenario [25,39] is a more progressive approach towards achieving zero GHG emissions by 2050 with less carbon budget allowance than the 2.0°C scenario. This scenario

focuses on the technical possibility of the energy transition with no special attention to the societal and political barriers. Immediate actions, fast deployment of RE, utilisation of efficient technologies and realisation of all available options are the main features of this scenario.

In the LUT scenarios, it is defined that all the historical capacities are decommissioned when reaching their technical lifetime. This scenario setup has been applied to the IEA and Teske/DLR scenarios as well, as far as it is in line with the given capacities in the references. If the installed capacity of a technology decreases continuously over time, but the capacity provided in the reference is still higher than what it was supposed to be due to its lifetime, the given capacity has been kept in the system even though it might have exceeded its technical lifetime. This issue mainly originated from the difference in assumptions, considering that all the models follow the same logic for decommissioning of an old capacity. Addition of fossil fuels capacity has been restricted to the existing installed capacity in both LUT and Teske/DLR scenarios except gas turbine power plants and combined heat and power (CHP) plants that run on hydrogen fuel or e-methane via power-to-gas (PtG) or biomethane.

Electricity generation and installed capacity of solar PV and wind power are reduced in the Teske/DLR scenarios to improve comparability. Due to the significant use of hydrogen and e-fuels in other energy sectors considered, solar PV and wind power reach the highest capacity and generation in these scenarios, especially towards the end of the transition period. At the same time, they are both variable RE sources, which require flexibility for a stable hourly electricity supply to meet the demand. For instance, CSP plus TES provide a dispatchable electricity supply. Reducing CSP capacity would put the model at a higher risk of an infeasible solution. Therefore, the amount of renewable hydrogen fuel is calculated based on the electricity generated (E_{genH_2}) via hydrogen combustion in gas turbines or in gas CHP or through an electrochemical process in fuel cell CHP divided by the respective efficiency of the plants (η_p). The calculated value is then divided by the electrolyser efficiency (η_e) taken from [25] to obtain the electricity required for electrolysis (E_{inputH_2}). Additionally, electricity required for e-fuels production is not included for the electricity sector alone as e-fuels are mainly used for the transport sector. With this information, the gross electricity demand ($E_{GrossDem}$), including the calculated electricity required for electrolysis, is subtracted from the total electricity generation (E_{Totgen}) to obtain the amount of electricity that must be excluded (E_r). This amount is multiplied by the ratio of solar PV and wind power to estimate how much of each capacity and generation must be reduced. Equations 1-3 consist of the steps described above.

$$H_2fuel_{RE} = \frac{E_{genH_2}}{\eta_P} \quad (1)$$

$$E_{inputH_2} = \frac{H_2fuel_{RE}}{\eta_e} \quad (2)$$

$$E_r = E_{Totgen} - E_{GrossDem} \quad (3)$$

Main assumptions, highlights and key features of the scenarios are shown in Table 1 of the main manuscript.

Note S5. Model setup

A myopic optimisation model, LUT-ESTM [24,42], is used in 5-year time steps from 2015 to 2050, where both the 2015 and the 2020 data are set as the starting years. The model aims to minimise the total annual system cost in every time step by capturing the more short-sighted decisions, subject to system constraints. LUT-ESTM contains the primary energy carriers, energy conversion, energy storage, and end-use sectoral demand. The installed technologies in every time step are taken to the next step until they reach their technical lifetime. In total, 9 world regions are simulated for 8 periods in an hourly resolution throughout a year, resulting collectively to 72 simulation runs for each transition pathway. From the total of 72 simulations, 18 simulation results are used identically across all scenarios as the starting years (2015 and 2020). This leads to 54 simulation runs over 9 scenarios, which is totalled to 486 simulation iterations. The simulation of the power system for every node is solved in around 1 h using 5-10 GB RAM for every period within a transition pathway. The modelling is conducted on an Intel® Xeon® Processor E5-2697 v3 with 28 cores and with 320 GB RAM. The overall structure of the modelling framework is illustrated in Figure S1.

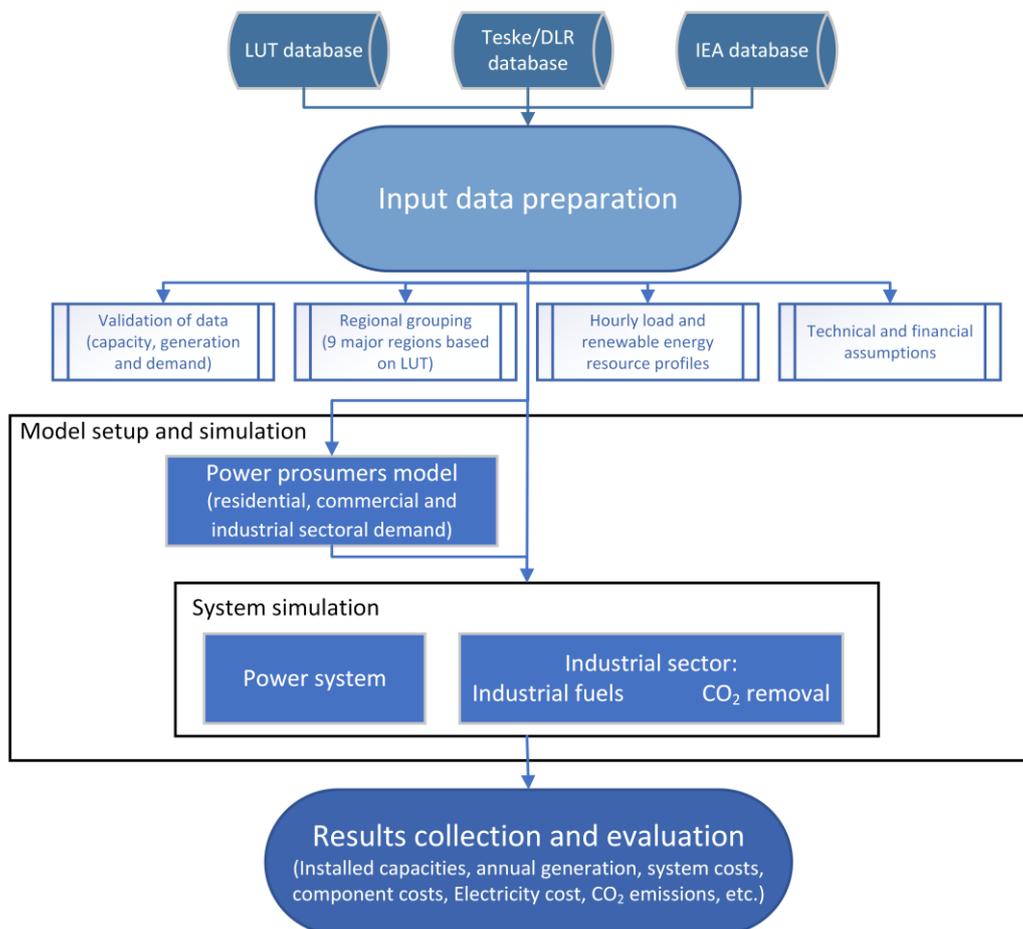


Figure S1. The overall structure of the LUT-ESTM used in this study

The target function of the system optimisation is calculated as the sum of the annual costs of installed technologies capacities, costs of generation, and production ramping. The target function of the applied energy model is shown in Equation 4.

$$\min \left(\sum_{r=1}^{reg} \sum_{t=1}^{tech} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_{t,r} + OPEXvar_t \cdot E_{gen,t,r} + rampCost_t \cdot totRamp_{t,r} \right) \quad (4)$$

Abbreviations: sub-regions (r , reg), generation, storage and transmission technologies (t , $tech$), capital expenditures for technology t ($CAPEX_t$), capital recovery factor for technology t (crf_t), fixed operational expenditures for technology t ($OPEXfix_t$), variable operational expenditures technology t ($OPEXvar_t$), installed capacity in the region r of technology t ($instCap_{t,r}$), annual generation by technology t in region r ($E_{gen,t,r}$), cost of ramping of technology t ($rampCost_t$) and sum of power ramping values during the year for the technology t in the region r ($totRamp_{t,r}$).

The electricity generation via prosumers is simulated in an independent sub-model. The target function includes annual costs of the prosumer electricity generation (solar PV) and storage (batteries), and the cost of electricity required from the distribution grid, as shown in Equation 5. Income of electricity feed-in to the distribution grid is reduced from the total annual cost.

$$\min \left(\sum_{t=1}^{tech} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_t + OPEXvar_t \cdot E_{gen,t} + elCost \cdot E_{grid} + elFeedIn \cdot E_{curt} \right) \quad (5)$$

Abbreviations: generation and storage technologies (t , $tech$), capital expenditures for technology t ($CAPEX_t$), capital recovery factor for technology t (crf_t), fixed operational expenditures for technology t ($OPEXfix_t$), variable operational expenditures technology t ($OPEXvar_t$), installed capacity of technology t ($instCap_t$), annual generation by technology t ($E_{gen,t}$), retail price of electricity ($elCost$), feed-in price of electricity ($elFeedIn$), annual amount of electricity required from the grid (E_{grid}), annual amount of electricity fed-in to the grid (E_{curt}).

The main constraint for the power system optimisation is the matching of the electricity generation and demand for every hour of the applied year as presented in Equation 6. In the current setup, no electricity exchange (imports and exports) is assumed between the nodes.

$$\begin{aligned} \forall h \in [1,8760] \quad & \sum_t^{tech} E_{gen,t} + \sum_r^{reg} E_{imp,r} + \sum_t^{stor} E_{stor,disch} \\ & = E_{demand} + \sum_r E_{exp,r} + \sum_t E_{stor,ch} + E_{curt} + E_{other} \end{aligned} \quad (6)$$

Abbreviations: hours (h), technology (t), all modelled power generation technologies ($tech$), region (r), all regions (reg), electricity generation (E_{gen}), electricity import (E_{imp}), storage technologies ($stor$), electricity from discharging storage ($E_{stor,disch}$), electricity demand (E_{demand}), electricity exported (E_{exp}), electricity for charging storage ($E_{stor,ch}$), electricity consumed by other sectors (i.e. heat, transport, industrial fuels production, CO₂ removal and desalination) (E_{other}), curtailed excess energy (E_{curt}). The energy loss in the high voltage direct current (HVDC) and alternating current (HVAC) transmission grids and energy storage technologies are considered in storage discharge and grid import value calculations.

Note S6. Regional decarbonisation narrative

In Figure S2, a ternary diagram is presented reflecting the contribution of RE, fossil fuels (with and without CCS) and nuclear throughout the transition, from 2020 to 2050. The integration of RE in each scenario depends largely on regional resources and constraints upon expanding renewables capacity.

As results suggest, all regions in the LUT scenarios rapidly shift towards fossil- and nuclear-free paths thanks to the sharp reduction of cost in solar PV, wind and battery storage. Regions located in the high latitudes enjoy the widely available and relatively well distributed wind resources, while Sunbelt regions take advantage of the inexpensive and abundant solar PV resources to satisfy the electricity demand. In the BPS-NWF, Europe and Eurasia (dominated mainly by Russia) hold the highest generation from wind energy among all regions by more than 20% and indicate a relatively fair contribution to the electricity supply mix. In fact, solar PV accounts for almost half of the total generation and wind plus other RE, mostly hydropower, generate the remaining electricity. The situation is different for the Middle East and North Africa (MENA), Northeast Asia, South Asian Association for Regional Cooperation (SAARC) and sub-Saharan Africa (SSA) in which solar PV stands as the dominant technology contributing to more than 80% of electricity generation by 2050. On the other hand, the penetration of wind power is considerably higher in some regions in the BPS-WF pathway due to renewal of the already decommissioned wind turbines. At the beginning of the trajectory, onshore wind is quite cost-competitive and a substantial capacity of wind power is added to the electricity system. This amount is typically decommissioned in the BPS-NWF by 2050 since the technical lifetime is reached, therefore, the old wind capacity is substituted with solar PV that is the sole cheapest option coupled with battery storage. The same aspect can be seen in the BPS-Plus scenarios as well. In North America, the share of wind energy in 2025 is just over 50% of the total RE generation, while solar PV and wind energy grow similarly starting from 2030 and eventually solar PV becomes the largest portion of renewable power generation by around 50%.

In the Teske/DLR scenarios, the share of RE technologies are more fairly distributed among technologies, where variable RE accounts for just under 60%, followed by CSP, geothermal, bioenergy. The overall difference between the two transition pathways is insignificant and both include a relatively comparable division between solar PV and wind energy. Although the regions in high altitude mainly use wind energy, regions near the equator have higher electricity

generation shares from solar PV, such as MENA, Southeast Asia, SAARC and SSA with 33% each.

The transition is counterintuitive for the IEA-STEPS, where solar PV and wind grow steadily over the transition and together amount to just 33% globally. Surprisingly, RE penetration remains almost stable throughout the transition for South and Central America, a region that generates approximately 80% of its electricity generation through RE sources today. The ratio of solar PV to the total electricity generation increases by just 7% over 30 years. Eurasia and MENA are the least-progressive regions considering the RE development and deployment with around 30% over the transition time horizon. In the SDS, however, the share of variable RE increases by 20% reaching to about 53% of the total RE electricity generation. Except for Eurasia, the rest of the regions integrate 70% or more RE into the electricity supply mix by 2050. Almost all regions show increasing nuclear power shares, while it is clearly commented in the WEO [35] that nuclear power is the by far highest cost option, followed by fossil CCS. Still, both options are strongly expanded in the SDS. This misbalance is even stronger in the Net Zero Emissions by 2050 (NZE2050) scenario, which could not be included in this research since the global data are only presented and the regional data are not disclosed. These observations further document the simulation type of the IEA scenarios, as fundamental cost aspects are not considered accordingly. This, however, may be a general deficit in current power system planning, thus, the IEA scenarios may reflect such energy policy deficits.

The penetration of solar PV and wind in the mix is compared with other RE and the results are shown in Figure S3. Since hydropower is currently the predominant RE source in the world, the starting points are centred around the other RE axis and in the northern part of the ternary diagram. The LUT cases are mainly driven by solar PV and wind energy, therefore, the directions of the paths are towards these two sources with some variations over the transition time horizon. In the Teske/DLR and IEA scenarios, the transition paths are more concentrated in the centre due to fairly distribution of RE sources leading to more straightforward trajectories and widely utilisation of resources with less focus on the future costs of individual technologies.

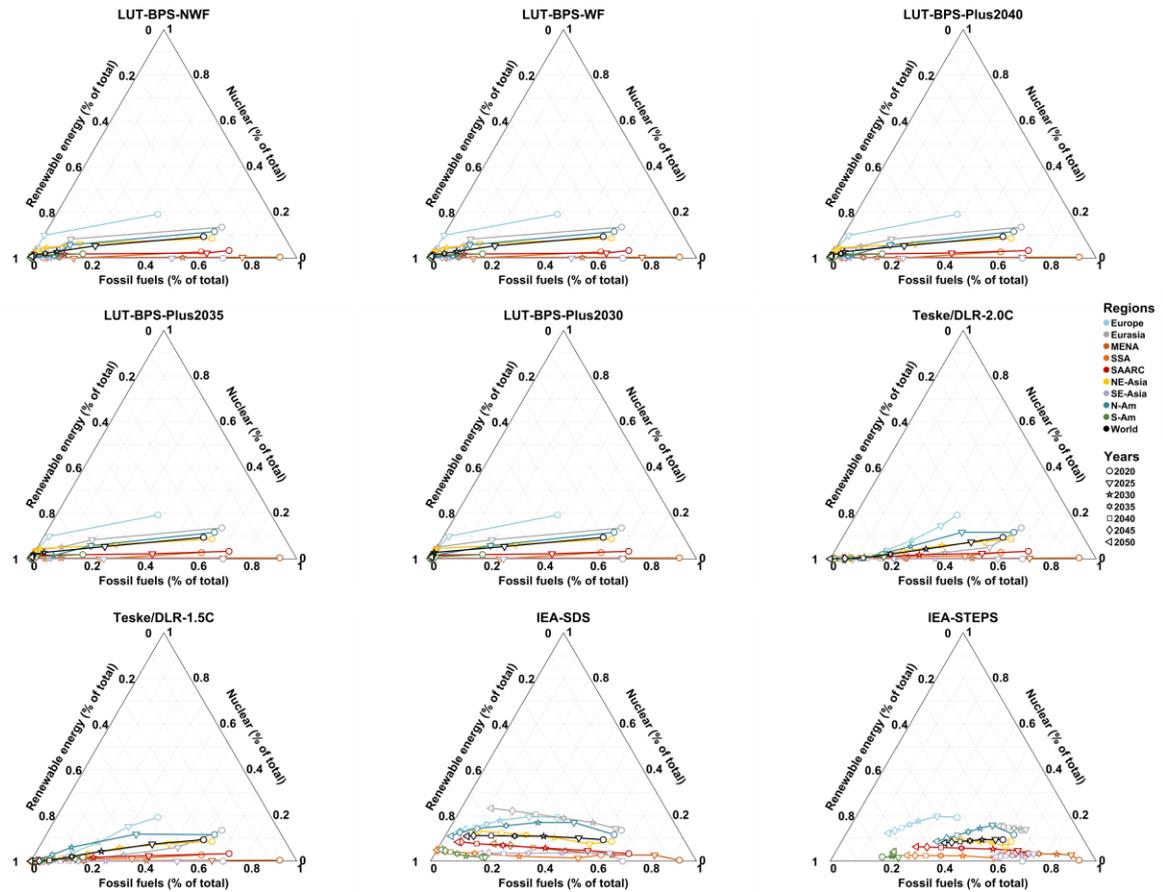


Figure S2. Ternary plots for the electricity generation mix per transition pathways. The total relative numbers add up to 1, meaning 100% of the total electricity generation. Fossil fuels include electricity generation with and without CCS. Markers are placed in every 5-year intervals from 2020 to 2050 to illustrate transition paths and their dynamics.

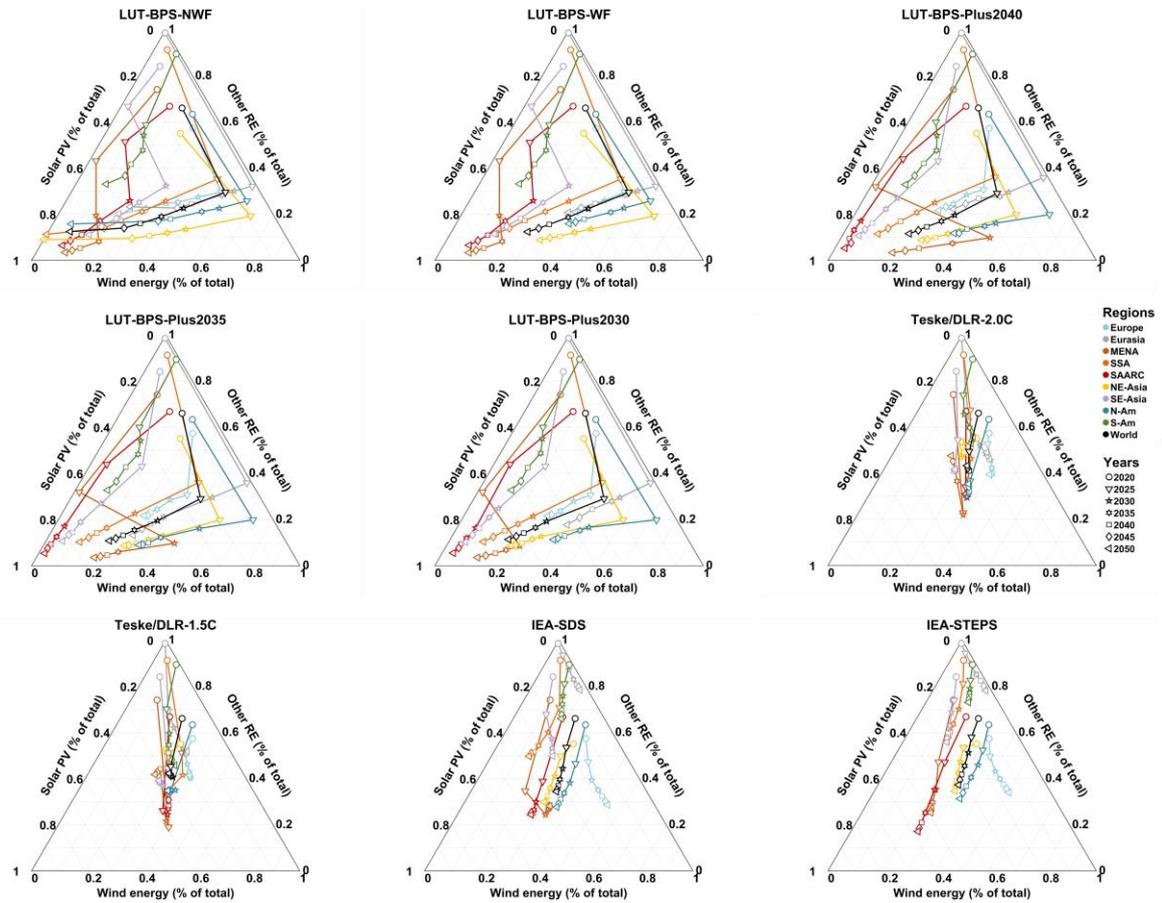


Figure S3. Ternary plots for the RE generation mix for all the explored scenarios throughout the transition. The total relative numbers add up to 1, meaning 100% of the total RE generation. Other RE consists of hydropower, bioenergy, CSP, ocean power, geothermal energy and renewable gas including hydrogen. Markers are placed in every 5-year intervals from 2020 to 2050 to illustrate transition paths and their dynamics.

Additionally, a comparison map diagram between the models' scenarios with the lowest and highest LCOE is presented in Figure S4. South and Central America has the least LCOE in the three scenarios thanks to high share of RE today, nearly 80% of total electricity generation from which the large portion belongs to hydropower, enabling the transition faster and easier than for instance for the MENA region. Northeast Asia together with Eurasia have the highest LCOE in all three scenarios. Several regions in the IEA scenarios have a LCOE of 60 €/MWh or higher, placing them as the most expensive scenario among all cases. However, even if the amount of cost differs significantly, the LUT and DLR/Teske scenarios show a similar regional distribution of low and high costs.

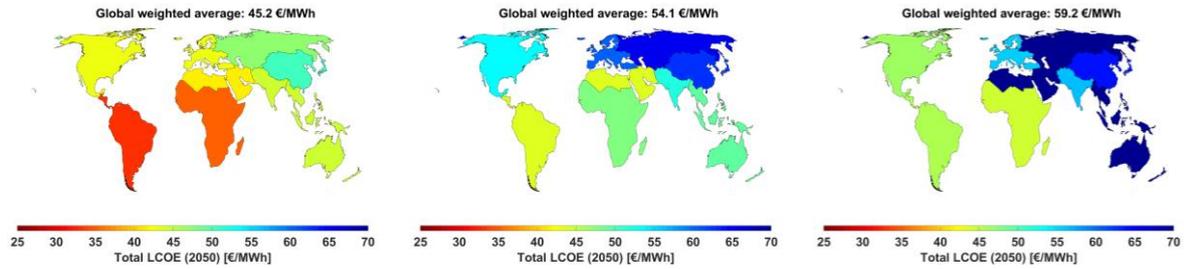
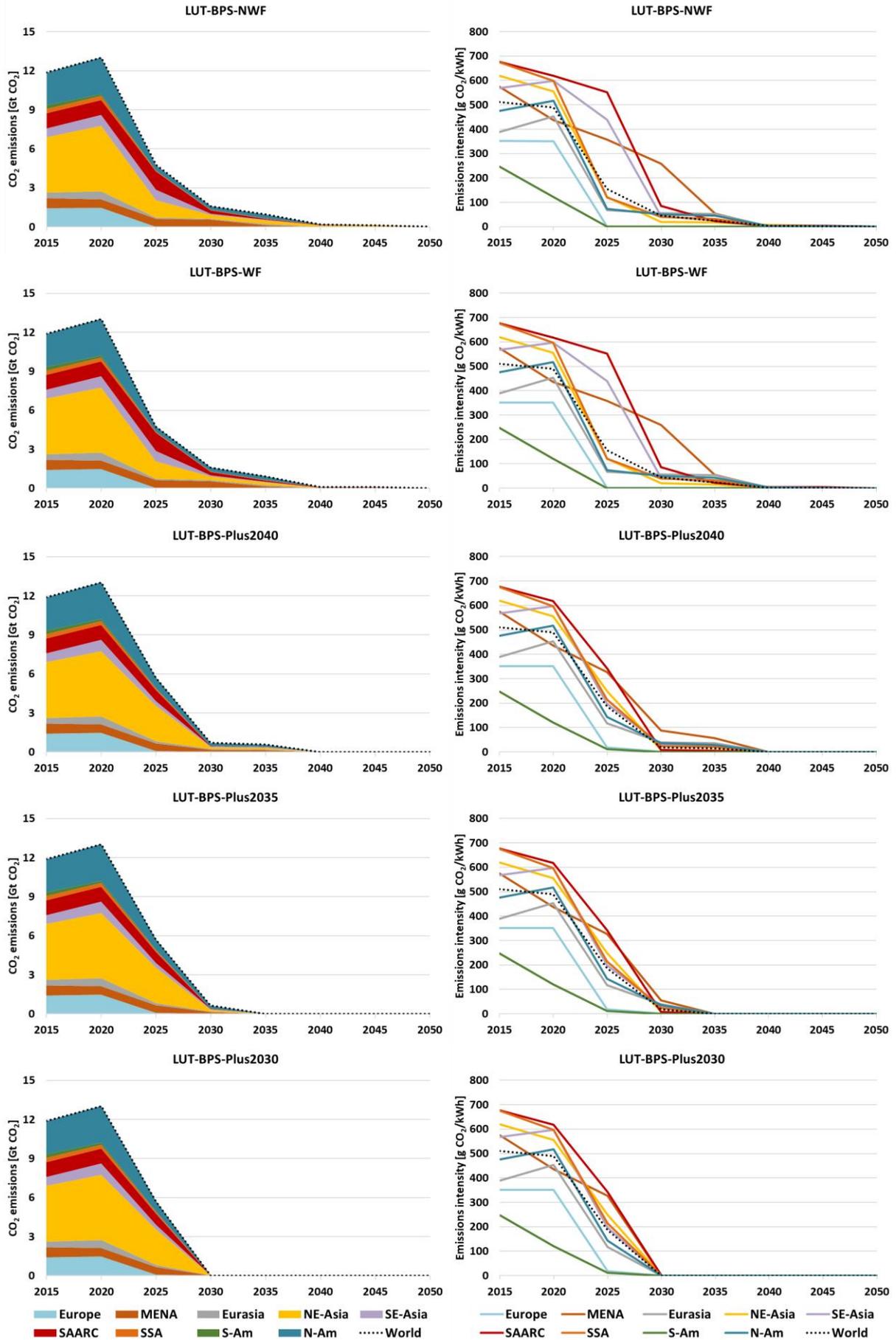


Figure S4. Regional LCOE for the LUT-BPS-Plus2040 (left), Teske/DLR-1.5°C (centre) and IEA-SDS (right) in 2050. The selected scenarios show the lowest LCOE by 2050 in each modelling group.

The development of CO₂ emissions and emissions intensity is shown in Figure S5 throughout the transition in 5-year intervals, from 2015 to 2050. In the LUT-BPSs, CO₂ emissions reduction occurs more drastically than the other scenarios. This is because considerable low-cost variable RE kick-in right at the beginning of the transition that reduce the dependency on fossil fuels power plants and thus decrease CO₂ emissions rapidly. South and Central America (S-Am) together with Europe can become carbon neutral between 2025-2030, with negligible amount of CO₂ emissions remaining in the electricity sector by latest up to 2040. The downward trend is slower in Northeast Asia (NE-Asia), North America (N-Am) and SAARC because these regions contain higher amounts of CO₂ emissions and less integration of RE in the electricity supply mix as of today. Therefore, the process of climate change mitigation takes longer in such regions. The same pattern can be seen in both Teske/DLR scenarios as well as the IEA-SDS. As a result of flexibility provided by the simulation tools, RE penetration and CO₂ emissions reduction can be smoothed over the transition time horizon. This allows for a smoother and slower pace of CO₂ emissions reduction than a rapid shift as noticed in the LUT cost-optimised cases. Eventually, it depends on the constraints and assumptions specified for the scenarios and change in any of the defined factors can lead to a different outcome.



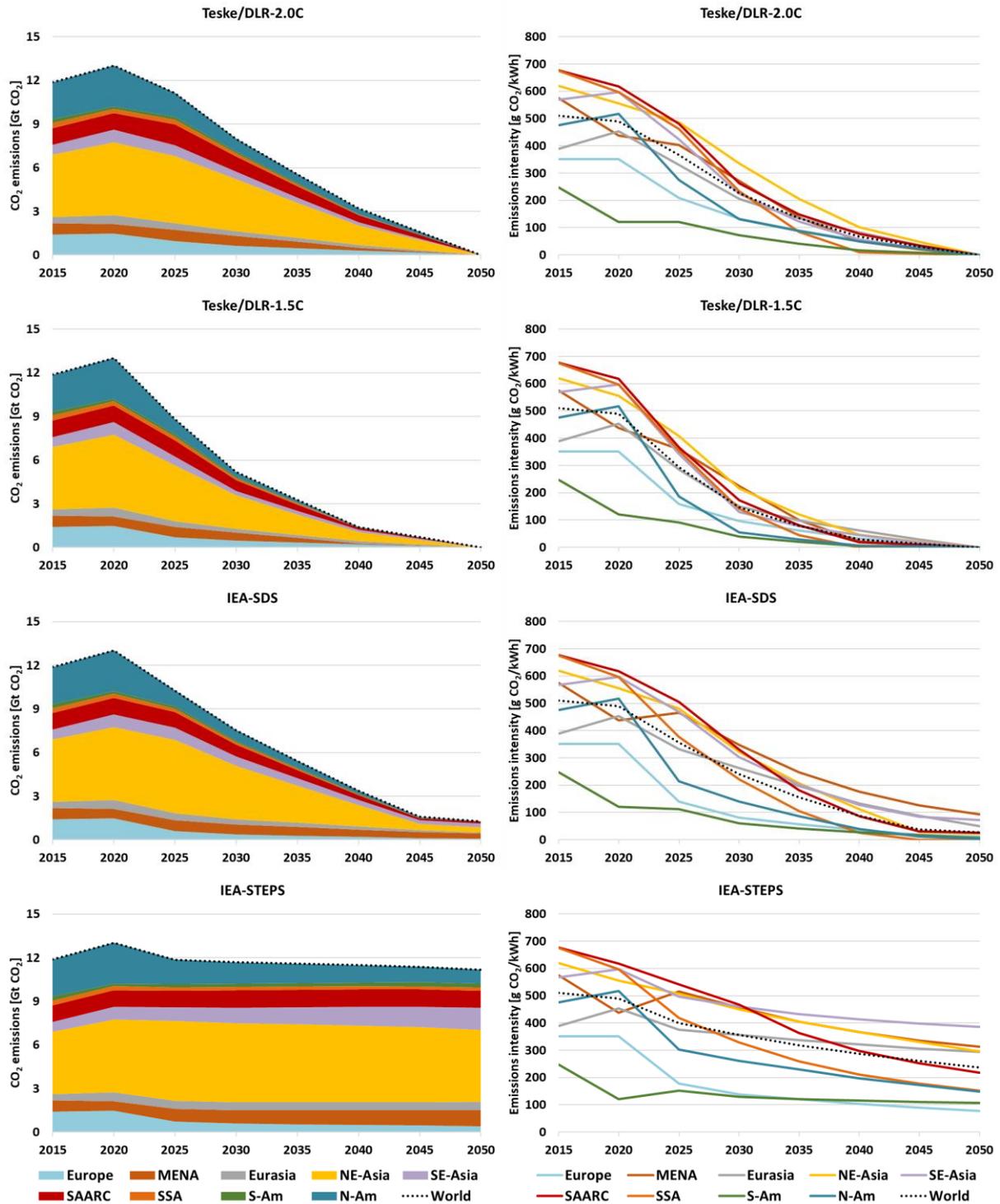


Figure S5. Development of regional CO₂ emissions and emissions intensity for the 9 major regions plus the world in the explored scenarios from 2015 to 2050

Figure S6 shows the hourly time series of the BPS-NWF, Teske/DLR-1.5°C and IEA-SDS scenarios with two example weeks in summer and winter for North America and MENA in 2050. The BPS-NWF mainly relies on solar PV technologies for electricity generation during

the day and on battery storage as a balancing option for the nights in both regions. This is driven by rapidly declining costs of these technologies that make them the primary choice of the optimiser. Contribution of wind power is limited in North America due to least-cost solar PV paired with batteries, especially in the central and southern parts, although together with hydropower, wind power meets part of the demand over winter nights and to a lesser extent during the summer nights. Thanks to a higher precipitation rate and more water resource availability in the winter, hydropower can accommodate PV power generation even during the daytime. In the summer week, higher electricity curtailment is observed due to higher solar radiation and relatively lower electricity demand compared to the example winter week. On the other hand, solar PV plus batteries is running the system almost entirely in MENA, with wind power only stepping in to bridge the gaps between supply and demand throughout the week. e-Methane powered by RE, hydropower and e-hydrogen from water electrolyzers provide flexibility to ensure electricity system reliability. For the Teske/DLR and IEA scenarios, the pattern and configuration of the power system are rather different. In both scenarios, energy security and the integration of a wide range of technologies plays a key role. In addition to solar PV and wind, CSP plus TES and hydrogen production are the dominant source of electricity supply. Interestingly, CSP generation is mainly stored in TES and utilised during the night hours. This aspect can be noticed because of low battery storage to couple with solar PV or wind power that results in converting the excess electricity to hydrogen and re-use it, by burning hydrogen in gas turbines or CHP fuel cells, when generation is not sufficient to meet the demand, or alternatively curtailing electricity when the demand is low such as the example winter week in MENA. For North America, a wider range of technologies shapes the power system. In the IEA scenario, gas turbines operate as a bridging technology and batteries cover a part of the demand to a lower degree during the nights in summer. In addition, nuclear and hydropower take part in electricity generation as well, especially in North America, complemented by biomass and geothermal energy.

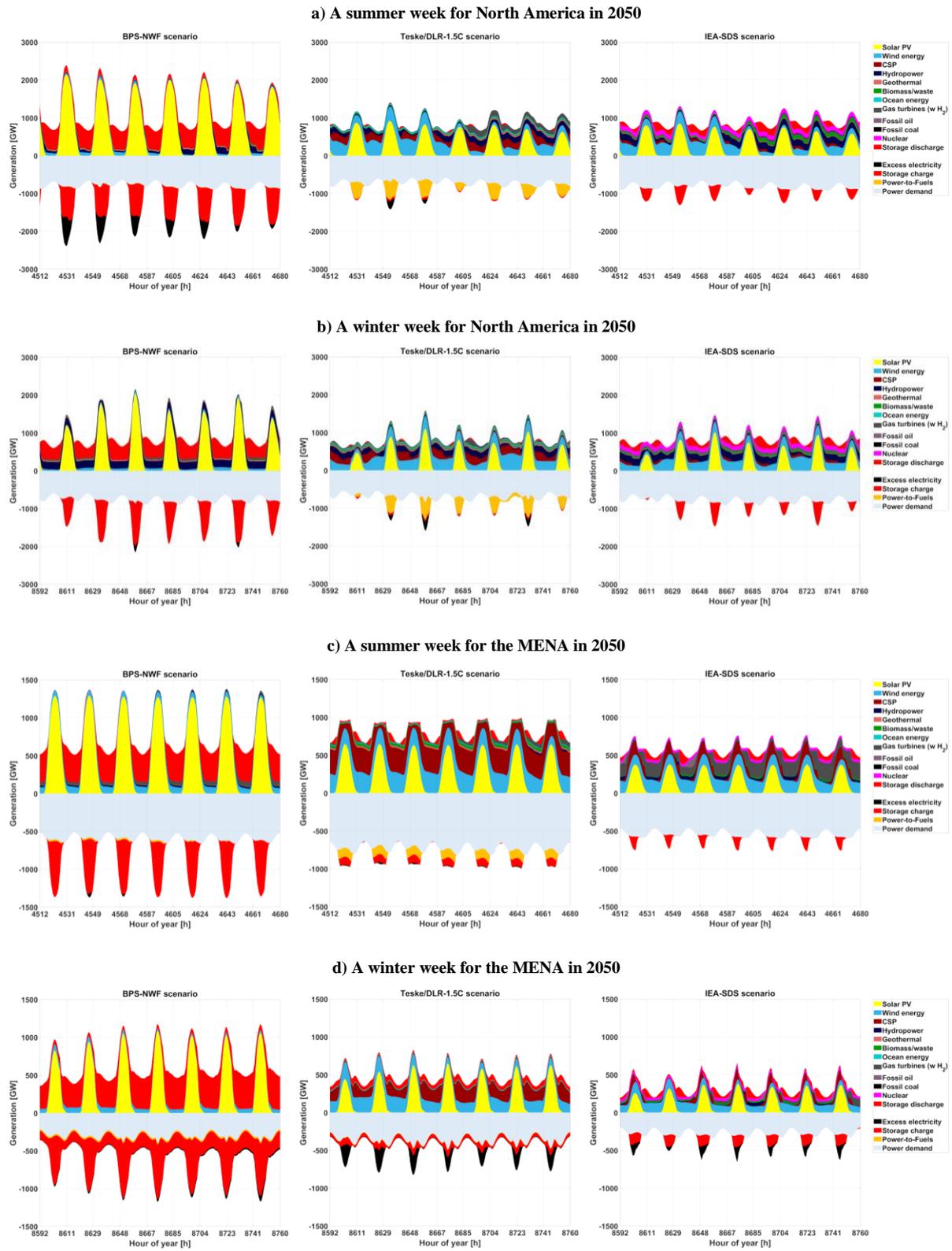


Figure S6. Hourly time series illustrating the balancing of all electricity generation and demand modelled by the LUT-ESTM for the BPS-NWF, Teske/DLR-1.5°C and IEA-SDS scenarios for the chosen summer and winter weeks for North America (top two rows), respectively, and for the MENA region (bottom two rows) accordingly in 2050. The positive y-axis represents electricity generation and storage discharge versus electricity demand including losses, storage charge, power-to-fuels and curtailment that are shown on the negative y-axis.

Note S7. Sensitivity analysis to economic parameter uncertainty

Energy transition pathways built on cost-optimisation versus energy diversity are discussed in the main article. As the LUT scenarios are developed based on a cost-optimised energy system model, they show the least-cost LCOE and transition pathway costs. However, it is crucial to examine the impact of cost sensitivity on the results because estimates for the future technological costs, yet to go through significant deployment, are uncertain. Therefore, a sensitivity of the technology choice and its impact on the overall system cost is investigated by applying the cost assumptions of the Teske/DLR scenarios [25,39] to all the scenarios. One of the main differences between the cost assumptions' structure is the regional specific costs in the Teske/DLR scenarios against the uniform cost assumptions for all regions as given in Table S2. The findings indicate that changing the cost assumptions does not change the results drastically, however, the LCOE and the annual system cost increase for all scenarios, as depicted in Figure S7. The largest deviation in terms of the global average LCOE in 2050 is noticed in the Teske-1.5°C by around 23%, increased from 54.1 €/MWh to 66.6 €/MWh, followed by Teske-2.0°C and IEA-SDS. On the other hand, the IEA-STEPS shows the least dependency on the cost assumptions as the share of fossil fuels remain very high throughout the transition period, indicating 7% and 12% increase in LCOE and total annual system costs in 2050. Meanwhile, the LCOE and the annual system costs in the LUT scenarios are raised by around 10-11% each. It should be noted that if the simulations of the LUT scenarios were re-conducted with different cost assumptions, the technology choice might have been different to some extent. Nonetheless, the dominant technologies for electricity generation, solar PV and onshore wind power, have the least-cost projections according to the Teske/DLR dataset as well. Because cost assumptions are associated with a level of uncertainty, the LCOE derived based on the cost assumptions will fall within a range. The cost trends, however, are stable and reliable across a large range of cost assumptions. It is vital to highlight that the costs are assumed identically across different world regions. However, regions-specific data is more realistic as the costs vary from one region to another. This aspect should be considered for future analysis.

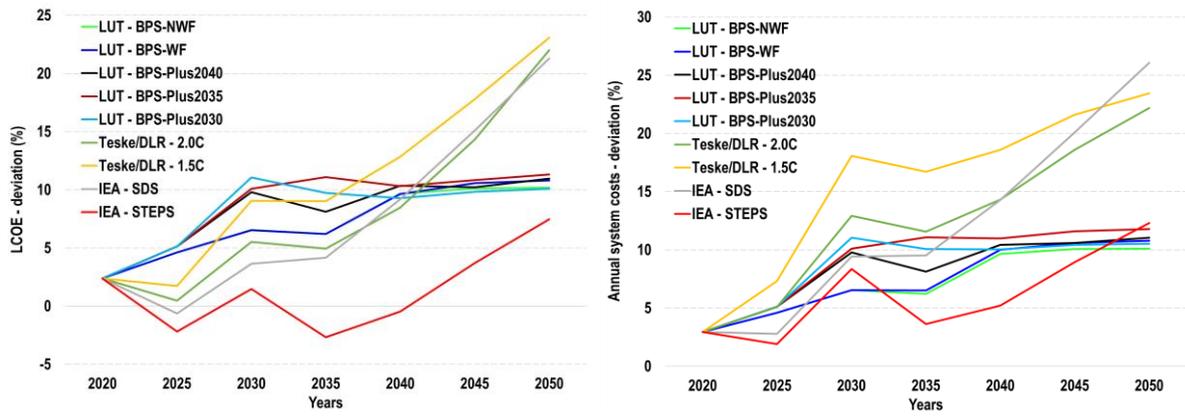


Figure S7. The deviation between the Teske/DLR and the LUT cost assumptions regarding the LCOE (left) and the total annual system costs (right) of all modelled scenarios.

Note S8. Further recommendations

The transparency, availability and accessibility of data are crucial factors that allow researchers to explore and investigate the already published results and come up with new solutions, improvements or verifications. This will take the science community one step further to a more concrete understanding of the known and unknown topics and shed a light for future research, innovation and development. Moreover, the policy-makers can benefit from a clean, well-documented and transparent input data and assumptions, which provides the ability of reproducibility. The open access platforms are a good start for reaching the audience widely across the world and eliminate the hurdle to access the publications, databases and materials. Both LUT [24,42] and Teske [25,39] most recent and flagship publications on global climate mitigation pathways were made open access. The IEA WEO flagship report and respective databases are only available for purchase with some specific discounts for academic and institutions. Although the most recent IEA report, World Energy Outlook 2021, is made publicly open and accessible, the extended database including regional data is only available for purchase. On top of that, the most progressive scenario ever published by IEA is the NZE2050, but the findings of this pathway are only provided on a global level. It is likely expected that in the next version the regional details will be accompanied by the report and published fully open access. Due to this fundamental lack of data and transparency the IEA-NZE2050 scenario could not be included in the analysis of this research. In addition, the energy system models should be made open source as well. None of the three models selected for this study is available as an open source model, which limits the opportunity for other energy systems analysts and modelers to examine the ability of these models, run a critical review and specify their pros and cons in comparison with other open source models [43–46]. It is planned for the LUT-ESTM to publish an open source version in future.

Increasing the rate of electrification can make the system more efficient and reliable [6,42]. To give an illustration, electricity can be fed into air-sourced and geothermal ground-sourced heat pumps with coefficient performance of 3 or higher that can provide both heating and cooling by factors more effective than fossil boilers. RE-based water desalination is another excellent application to provide fresh water for various purposes utilising primary energy more efficient by about a factor of 30 in electricity-based versus thermal processes, as discussed by Caldera et al. [47–49]. These items will be further investigated and reported in the future research work for analysis of all energy sectors.

A recent article [50] exploring the historical publications around 100% RE-based systems present that there are no techno-economic barriers against such a system transition. Additionally, 100% RE-based systems can meet all energy demand of countries worldwide at low cost. This analysis showcases that energy system model developers agreed that solar PV and wind power account for majority of electricity supply, but some also showed solar PV and wind power can supply at least 80% of the primary energy demand in a fully RE system. Since 2017, hundreds of published papers by various research groups confirmed that 100% RE-based systems are not only feasible, but also quite affordable. This consensus is against the criticism of technical feasibility, but also affordability, of a fully renewables-based energy system, such as Clack et al. [51], Trainer [52] and Heard et al. [53], when examined in detail as explained by Brown et al. [54], Diesendorf and Elliston [55], Aghahosseini et al. [56] and Jacobson et al. [57,58], and summarised in Breyer et al. [50] for various cases.

Additional tables and figures

Table S2. Financial assumptions for the technologies included in the model.

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050
PV fixed tilted [59–61]	Capex	€/kW _{el}	1000	432	336	278	237	207	184	166
	Opex fix	€/(kW _{el} a)	15.0	7.8	6.5	5.7	5.0	4.5	4.0	3.7
	Opex var	€/kW _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	30	30	35	35	35	40	40	40
PV rooftop – Residential [60,61]	Capex	€/kW _{el}	1360	1045	842	715	622	551	496	453
	Opex fix	€/(kW _{el} a)	20.4	9.1	7.7	6.7	5.9	5.3	4.8	4.4
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	30	30	35	35	35	40	40	40
PV rooftop – Commercial [60,61]	Capex	€/kW _{el}	1360	689	544	456	393	345	308	280
	Opex fix	€/(kW _{el} a)	20.4	9.1	7.7	6.7	5.9	5.3	4.8	4.4
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	30	30	35	35	35	40	40	40
PV rooftop – Industrial [60,61]	Capex	€/kW _{el}	1360	512	397	329	281	245	217	197
	Opex fix	€/(kW _{el} a)	20.4	9.1	7.7	6.7	5.9	5.3	4.8	4.4
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	30	30	35	35	35	40	40	40
PV single-axis tracking [59,61,62]	Capex	€/kW _{el}	1150	475	370	306	261	228	202	183
	Opex fix	€/(kW _{el} a)	17.3	8.5	7.2	6.2	5.5	4.9	4.4	4.1
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	30	30	35	35	35	40	40	40
Wind onshore [63–65]	Capex	€/kW _{el}	1250	1150	1060	1000	965	940	915	900
	Opex fix	€/(kW _{el} a)	25.0	23.0	21.2	20.0	19.3	18.8	18.3	18.0
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	25	25	25	25
Wind offshore [66]	Capex	€/kW _{el}	3220	2973	2561	2287	2216	2168	2145	2130
	Opex fix	€/(kW _{el} a)	112.7	85.0	73.0	65.9	64.0	62.0	61.0	60.7

	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	20	25	25	25	25	25	25	25
Hydro run-of-river [65]	Capex	€/kW _{el}	2560	2560	2560	2560	2560	2560	2560	2560
	Opex fix	€/(kW _{el} a)	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8
	Opex var	€/kWh _{el}	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
	Lifetime	years	50	50	50	50	50	50	50	50
Hydro reservoir/ Dam [65]	Capex	€/kW _{el}	1650	1650	1650	1650	1650	1650	1650	1650
	Opex fix	€/(kW _{el} a)	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5
	Opex var	€/kWh _{el}	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
	Lifetime	years	50	50	50	50	50	50	50	50
Ocean energy (wave) [25,65]	Capex	€/kW _{el}	5792	5542	4604	3667	3125	2583	2171	1758
	Opex fix	€/(kW _{el} a)	231.7	221.7	184.2	146.7	125.0	103.3	86.8	70.3
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20	20
Concentrating solar thermal (CSP) – solar field, parabolic trough [67,68]	Capex	€/kW _{el}	438	345	304	275	251	230	212	196
	Opex fix	€/(kW _{el} a)	10.1	7.9	7	6.3	5.8	5.3	4.9	4.5
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	25	25	25	25
Geothermal PP [65,69]	Capex	€/kW _{el}	5250	4970	4720	4470	4245	4020	3815	3610
	Opex fix	€/(kW _{el} a)	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	40	40	40	40	40	40	40	40
	Efficiency	%	24	24	24	24	24	24	24	24
Steam turbine (CSP) [67,68]	Capex	€/kW _{el}	1000	968	946	923	902	880	860	840
	Opex fix	€/(kW _{el} a)	20.0	19.4	18.9	18.5	18.0	17.6	17.2	16.8
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	30	30	30	30
	Efficiency	%	37	38	40	43	43	43	43	43

CCGT PP [70]	Capex	€/kW _{el}	775	775	775	775	775	775	775	775
	Opex fix	€/(kW _{el} a)	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
	Opex var	€/kWh _{el}	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
	Lifetime	years	35	35	35	35	35	35	35	35
	Efficiency	%	58	58	58	58	59	60	60	60
CCGT PP with CCS [37,38,70]	Capex	€/kW _{el}	2565	2565	2273	1980	1845	1710	1640	1570
	Opex fix	€/(kW _{el} a)	81	81	72	63	58.5	54	52	50
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	CO ₂ transport & storage	€/tCO ₂	45	45	45	45	40	36	33	30
	Lifetime	years	35	35	35	35	35	35	35	35
	Efficiency	%	52	52	53	53	53	54	54	55
OCGT PP [65,71]	Capex	€/kW _{el}	475	475	475	475	475	475	475	475
	Opex fix	€/(kW _{el} a)	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
	Opex var	€/kWh _{el}	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011
	Lifetime	years	35	35	35	35	35	35	35	35
	Efficiency	%	40	40	42	43	44	44	45	45
Internal combustion generator [64]	Capex	€/kW _{el}	385	385	385	385	385	385	385	385
	Opex fix	€/(kW _{el} a)	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
	Opex var	€/kWh _{el}	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	%	30	30	30	30	30	30	30	30
Coal PP [65]	Capex	€/kW _{el}	1600	1600	1600	1600	1600	1600	1600	1600
	Opex fix	€/(kW _{el} a)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
	Opex var	€/kWh _{el}	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	45	45	45	45	45	45	45	45
	Efficiency	%	43	43	43	43	43	43	43	43
Coal PP with CSS [37,38,70]	Capex	€/kW _{el}	4590	4590	4095	3600	3375	3150	3035	2920
	Opex fix	€/(kW _{el} a)	162.0	162.0	148.5	135.0	126.0	117.0	112.5	108.0

	Opex var	€/kWh _{el}	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	CO ₂ transport & storage	€/tCO ₂	45	45	45	45	40	36	33	30
	Lifetime	years	45	45	45	45	45	45	45	45
	Efficiency	%	37	37	38	39	40	40	41	41
Biomass PP [65]	Capex	€/kW _{el}	2755	2620	2475	2330	2195	2060	1945	1830
	Opex fix	€/(kW _{el} a)	55.4	47.2	44.6	41.9	39.5	37.1	35.0	32.9
	Opex var	€/kWh _{el}	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
	Lifetime	years	25	25	25	25	25	25	25	25
	Efficiency	%	35	36	37	37	38	38	39	39
Nuclear PP [29,65,72]	Capex	€/kW _{el}	6210	6003	6003	5658	5658	5244	5244	5175
	Opex fix	€/(kW _{el} a)	117.0	113.1	113.1	98.4	98.4	83.6	83.6	78.8
	Opex var	€/kWh _{el}	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
	Lifetime	years	40	40	40	40	40	40	40	40
	Efficiency	%	33	37	37	38	38	38	38	38
CHP Gas [65]	Capex	€/kW _{el}	880	880	880	880	880	880	880	880
	Opex fix	€/(kW _{el} a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
	Opex var	€/kWh _{el}	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	electric %	50	51	52	53	53	54	54	55
CHP Oil [65]	Capex	€/kW _{el}	880	880	880	880	880	880	880	880
	Opex fix	€/(kW _{el} a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
	Opex var	€/kWh _{el}	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	electric %	30	30	30	30	30	30	30	30
CHP Coal [65]	Capex	€/kW _{el}	2030	2030	2030	2030	2030	2030	2030	2030
	Opex fix	€/(kW _{el} a)	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7
	Opex var	€/kWh _{el}	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
	Lifetime	years	40	40	40	40	40	40	40	40

	Efficiency	electric %	38	41	42	43	44	44	45	45
CHP Biomass [73]	Capex	€/kW _{el}	3500	3400	3300	3200	3125	3050	2975	2900
	Opex fix	€/(kW _{el} a)	100.5	97.6	94.95	92.3	90.8	89.3	87.8	86.3
	Opex var	€/kWh _{el}	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
	Lifetime	years	25	25	25	25	25	25	25	25
	Efficiency	electric %	29	30	30	30	29	29	29	29
CHP Biogas [42]	Capex	€/kW _{el}	503	429	400	370	340	326	311	296
	Opex fix	€/(kW _{el} a)	20.1	17.2	16.0	14.8	13.6	13.0	12.4	11.8
	Opex var	€/kWh _{el}	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	electric %	33	34	37	40	42	44	44	44
CHP MSW (waste incinerator) [65]	Capex	€/kW _{el}	5940	5630	5440	5240	5030	4870	4690	4540
	Opex fix	€/(kW _{el} a)	267.3	253.4	244.8	235.8	226.4	219.2	211.1	204.3
	Opex var	€/kWh _{el}	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	electric %	24	26	26	26	26	26	26	26
CHP Fuel cell [15,25,65]	Capex	€/kW _{el}	4167	4167	3125	2083	2083	2083	1508	933
	Opex fix	€/(kW _{el} a)	125.0	125.0	93.8	62.5	62.5	62.5	45.3	28.0
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20	20
	Efficiency	electric %	36	37	37	38	38	39	39	39
Water electrolysis [74,75]	Capex	€/kW _{H2}	938	803	586	446	381	347	313	291
	Opex fix	€/(kW _{H2} a)	37.5	28.1	20.5	15.6	13.3	12.1	11.0	10.2
	Opex var	€/kWh _{H2}	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	%	64	70	70	70	70	70	70	70
	Lower heating value	MJ/kg	121	121	121	121	121	121	121	121

CO ₂ direct air capture [38]	Capex	€/tCO ₂ a	1000	730	481	338	281	237	217	199
	Opex fix	€/tCO ₂ a	40.0	29.2	19.2	13.5	11.2	9.5	8.7	8.0
	Opex var	€/tCO ₂	0	0	0	0	0	0	0	0
	Lifetime	years	20	20	25	25	30	30	30	30
	El. cons.	kWh _{el} /tCO ₂	250	250	237	225	213	203	192	182
	Heat cons.	kWh _{th} /tCO ₂	1750	1750	1618	1500	1387	1286	1189	1102
Methanation [74,75]	Capex	€/kW _{SNG}	607	558	409	309	274	251	227	211
	Opex fix	€/kW _{SNG} a	27.9	25.7	18.8	14.2	12.6	11.5	10.4	9.7
	Opex var	€/MWh _{SNG}	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	%	82	82	82	82	82	82	82	82
	CO ₂ input	kgCO ₂ /kWh _{th}	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Biogas digester [76]	Capex	€/kW _{th}	856	811	784	755	725	702	676	654
	Opex fix	€/kW _{th} a	34.2	32.5	31.4	30.2	29.0	28.1	27.0	26.2
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	25	25	25	25
	Efficiency	%	100	100	100	100	100	100	100	100
Biogas upgrade [76]	Capex	€/kW _{th}	378	322	300	278	255	244	233	222
	Opex fix	€/kW _{th} a	30.2	25.8	24.0	22.2	20.4	19.5	18.7	17.8
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	20	20	20	20	20	20	20	20
	Efficiency	%	98	98	98	98	98	98	98	98
Battery storage [59,60,68]	Capex	€/kWh _{el}	400	234	153	110	89	76	68	61
	Opex fix	€/kWh _{el} a	24.00	3.28	2.60	2.20	2.05	1.90	1.77	1.71
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
	Efficiency	%	90	91	92	93	94	95	95	95
	Capex	€/kW _{el}	200	117	76	55	44	37	33	30

Battery storage interface [60,68,77–79]	Opex fix	€/kW _{el} a)	0	1.64	1.29	1.10	1.01	0.93	0.86	0.84
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – res. Storage [59,60]	Capex	€/kWh _{el}	603	462	308	224	182	156	140	127
	Opex fix	€/kW _{el} a)	36.20	5.08	4.00	3.36	3.09	2.81	2.80	2.54
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – res. storage interface [59,60]	Capex	€/kW _{el}	302	231	153	112	90	76	68	62
	Opex fix	€/kW _{el} a)	0	2.54	1.99	1.68	1.53	1.37	1.36	1.24
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – com. storage [59,60]	Capex	€/kWh _{el}	513	366	240	175	141	121	108	98
	Opex fix	€/kW _{el} a)	30.80	4.39	3.60	2.98	2.68	2.54	2.38	2.25
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – com. storage interface [59,60]	Capex	€/kW _{el}	256	183	119	88	70	59	53	48
	Opex fix	€/kW _{el} a)	0	2.20	1.79	1.50	1.33	1.24	1.17	1.10
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – ind. storage [59,60]	Capex	€/kWh _{el}	435	278	181	131	105	90	80	72
	Opex fix	€/kW _{el} a)	26.1	3.89	3.08	2.62	2.42	2.25	2.08	1.94
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Battery prosumer – ind. storage interface [59,60]	Capex	€/kW _{el}	218	139	90	66	52	44	39	35
	Opex fix	€/kW _{el} a)	0	1.95	1.53	1.32	1.20	1.10	1.01	0.95
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	15	20	20	20	20	20	20	20
Pumped hydro energy storage (PHES) [65,80]	Capex	€/kWh _{el}	8	8	8	8	8	8	8	8
	Opex fix	€/kW _{el} a)	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34

	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50	50
	Efficiency	%	85	85	85	85	85	85	85	85
PHES interface [65,80]	Capex	€/kW _{el}	650	650	650	650	650	650	650	650
	Opex fix	€/(kW _{el} a)	0	0	0	0	0	0	0	0
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50	50
Adiabatic compressed air energy storage (A- CAES) [42,65]	Capex	€/kWh _{el}	75	75	65	58	54	51	47	44
	Opex fix	€/(kW _{el} a)	1.29	1.16	0.99	0.87	0.81	0.77	0.71	0.66
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	40	40	40	40	40	40	40	40
	Efficiency	%	54	59	65	70	70	70	70	70
A-CAES interface [42,65]	Capex	€/kW _{el}	540	540	540	540	540	540	540	540
	Opex fix	€/(kW _{el} a)	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
	Opex var	€/kWh _{el}	0	0	0	0	0	0	0	0
	Lifetime	years	40	40	40	40	40	40	40	40
Thermal energy storage (TES) [42]	Capex	€/kWh _{th}	51	42	33	27	23	21	19	18
	Opex fix	€/(kWh _{th} a)	0.76	0.63	0.49	0.4	0.35	0.32	0.29	0.26
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	30	30	30	30
	Efficiency	%	90	90	90	90	90	90	90	90
TES interface [42]	Capex	€/kWh _{th}	0	0	0	0	0	0	0	0
	Opex fix	€/(kWh _{th} a)	0	0	0	0	0	0	0	0
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	30	30	30	30
Hydrogen storage [81]	Capex	€/kWh _{th}	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
	Opex fix	€/(kWh _{th} a)	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011
	Opex var	€/kWh _{th}	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001

	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	%	100	100	100	100	100	100	100	100
Hydrogen storage interface [81]	Capex	€/kW _{th}	100	100	100	100	100	100	100	100
	Opex fix	€/(kW _{th} a)	4	4	4	4	4	4	4	4
	Opex var	€/kW _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	15	15	15	15	15	15	15	15
CO ₂ storage [82]	Capex	€/ton	142	142	142	142	142	142	142	142
	Opex fix	€/(ton a)	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
	Opex var	€/ton	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
	Lifetime	years	30	30	30	30	30	30	30	30
	Efficiency	%	100	100	100	100	100	100	100	100
CO ₂ storage interface [82]	Capex	€/ton/h	0	0	0	0	0	0	0	0
	Opex fix	€/(ton/h a)	0	0	0	0	0	0	0	0
	Opex var	€/ton	0	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50	50
Gas storage [81]	Capex	€/kWh _{th}	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Opex fix	€/(kWh _{th} a)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	50	50	50	50	50	50	50	50
	Efficiency	%	100	100	100	100	100	100	100	100
Gas storage interface [81]	Capex	€/kW _{th}	100	100	100	100	100	100	100	100
	Opex fix	€/(kW _{th} a)	4	4	4	4	4	4	4	4
	Opex var	€/kW _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	15	15	15	15	15	15	15	15
District heat storage [42]	Capex	€/kWh _{th}	50	40	30	30	25	20	20	20
	Opex fix	€/(kWh _{th} a)	0.75	0.6	0.45	0.45	0.375	0.3	0.3	0.3
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	30	30	30	30

	Efficiency	%	90	90	90	90	90	90	90	90
District heat storage interface [42]	Capex	€/kWh _{th}	0	0	0	0	0	0	0	0
	Opex fix	€/(kWh _{th} a)	0	0	0	0	0	0	0	0
	Opex var	€/kWh _{th}	0	0	0	0	0	0	0	0
	Lifetime	years	25	25	25	25	30	30	30	30

Table S3. Ramping costs for electricity generation technologies [83].

Technology	Unit	Value
Geothermal power	€/MW	0.0
Coal PP	€/MW	54.3
Nuclear PP	€/MW	54.3
CCGT	€/MW	25.0
OCGT	€/MW	22.9
Internal Combustion Generator	€/MW	0.0
Biomass PP	€/MW	54.3
Steam Turbine (CSP)	€/MW	0.0
CHP NG	€/MW	22.9
CHP Oil	€/MW	0.0
CHP Coal	€/MW	54.3
CHP Biomass	€/MW	54.3
CHP Biogas	€/MW	22.9
CHP MSW (Waste incinerator)	€/MW	54.3

Table S4. Assumed prices for fossil and nuclear fuels.

Component	Unit	2015	2020	2025	2030	2035	2040	2045	2050	Refs.
Coal	€/MWh _{th}	7.7	7.7	8.4	9.2	10.2	11.1	11.1	11.1	[84]
Fuel Oil	€/MWh _{th}	52.5	35.2	39.8	44.4	43.9	43.5	43.5	43.5	[29]
Fossil gas	€/MWh _{th}	21.8	22.2	30.0	32.7	36.1	40.2	40.2	40.2	[84]
Uranium	€/MWh _{th}	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	[85]

Table S5. CO₂ emissions assumptions by fuel type.

Component	Unit	Emissions intensity	Refs.
Coal	tCO ₂ /MWh _{th}	0.34	[86]
Oil	tCO ₂ /MWh _{th}	0.28	[86]
Gas	tCO ₂ /MWh _{th}	0.24	[87]

Table S6. CO₂ emissions cost by major regions and scenarios (€/tCO₂). References for the years 2015 and 2020 are based on [88–90].

Regions	2015	2020	2025	2030	2035	2040	2045	2050
LUT-BPS scenarios [84]								
Europe	7.2	25.0	52.0	61.0	68.0	75.0	100.0	150.0
Eurasia	4.5	4.5	52.0	61.0	68.0	75.0	100.0	150.0
MENA	6.6	7.0	52.0	61.0	68.0	75.0	100.0	150.0
SSA	6.6	7.0	52.0	61.0	68.0	75.0	100.0	150.0
SAARC	6.0	8.4	52.0	61.0	68.0	75.0	100.0	150.0
NE-Asia	6.5	11.4	52.0	61.0	68.0	75.0	100.0	150.0
SE-Asia	7.5	9.2	52.0	61.0	68.0	75.0	100.0	150.0
N-Am	12.7	20.5	52.0	61.0	68.0	75.0	100.0	150.0
S-Am	4.5	4.5	52.0	61.0	68.0	75.0	100.0	150.0
IEA-SDS and Teske/DLR scenarios [27]								
Europe	7.2	25.0	52.5	73.9	95.3	116.7	138.1	159.4
Eurasia	4.5	4.5	35.8	58.6	81.4	104.2	126.9	149.7
MENA	6.6	7.0	35.8	58.6	81.4	104.2	126.9	149.7
SSA	6.6	7.0	35.8	58.6	81.4	104.2	126.9	149.7
SAARC	6.0	8.4	35.8	58.6	81.4	104.2	126.9	149.7
NE-Asia	6.5	11.4	52.5	73.9	95.3	116.7	138.1	159.4
SE-Asia	7.5	9.2	35.8	58.6	81.4	104.2	126.9	149.7
N-Am	12.7	20.5	52.5	73.9	95.3	116.7	138.1	159.4
S-Am	4.5	4.5	35.8	58.6	81.4	104.2	126.9	149.7
IEA-STEPS scenario [27]								
Europe	7.2	25.0	28.3	33.3	38.3	43.3	48.3	53.3
Eurasia	4.5	4.5	6.7	10.0	13.3	16.7	20.0	23.3
MENA	6.6	7.0	8.3	12.2	16.1	20.0	23.9	27.8
SSA	6.6	7.0	8.3	12.2	16.1	20.0	23.9	27.8
SAARC	6.0	8.4	11.3	15.7	20.1	24.6	29.0	33.5
NE-Asia	6.5	11.4	16.9	21.9	26.9	31.9	36.9	41.9
SE-Asia	7.5	9.2	12.3	16.4	20.6	24.7	28.8	32.9
N-Am	12.7	20.5	28.3	29.4	30.6	31.7	32.8	33.9
S-Am	4.5	4.5	6.7	10.0	13.3	16.7	20.0	23.3

Table S7. Electricity retail prices assumptions for sectoral consumers by major regions in the scenarios. Data are extracted from [24] for 145 regions and weighted using the corresponding sectoral demand.

Regions	Unit	2015	2020	2025	2030	2035	2040	2045	2050
Residential									
Europe	[€/kWh]	0.158	0.182	0.205	0.231	0.254	0.273	0.273	0.288
Eurasia	[€/kWh]	0.033	0.042	0.036	0.046	0.040	0.051	0.044	0.056
MENA	[€/kWh]	0.029	0.037	0.046	0.057	0.070	0.086	0.103	0.122
SSA	[€/kWh]	0.056	0.068	0.086	0.105	0.126	0.150	0.174	0.197
SAARC	[€/kWh]	0.061	0.078	0.098	0.123	0.147	0.170	0.170	0.197
NE-Asia	[€/kWh]	0.097	0.116	0.100	0.121	0.105	0.128	0.111	0.136
SE-Asia	[€/kWh]	0.078	0.093	0.111	0.133	0.157	0.180	0.175	0.202
N-Am	[€/kWh]	0.095	0.118	0.140	0.163	0.190	0.219	0.247	0.267
S-Am	[€/kWh]	0.118	0.141	0.167	0.194	0.215	0.235	0.256	0.274
Commercial									
Europe	[€/kWh]	0.132	0.156	0.180	0.205	0.231	0.254	0.273	0.290
Eurasia	[€/kWh]	0.036	0.046	0.044	0.051	0.049	0.056	0.054	0.062
MENA	[€/kWh]	0.034	0.040	0.049	0.061	0.076	0.094	0.111	0.132
SSA	[€/kWh]	0.050	0.063	0.081	0.103	0.127	0.153	0.180	0.207
SAARC	[€/kWh]	0.088	0.085	0.107	0.132	0.155	0.180	0.209	0.239
NE-Asia	[€/kWh]	0.089	0.108	0.101	0.113	0.107	0.120	0.114	0.128
SE-Asia	[€/kWh]	0.076	0.093	0.112	0.135	0.159	0.182	0.206	0.231
N-Am	[€/kWh]	0.097	0.112	0.135	0.159	0.184	0.211	0.240	0.263
S-Am	[€/kWh]	0.103	0.127	0.150	0.175	0.199	0.224	0.245	0.263
Industrial									
Europe	[€/kWh]	0.100	0.122	0.144	0.169	0.196	0.224	0.244	0.263
Eurasia	[€/kWh]	0.040	0.051	0.053	0.056	0.059	0.062	0.065	0.068
MENA	[€/kWh]	0.033	0.043	0.054	0.068	0.085	0.104	0.125	0.148
SSA	[€/kWh]	0.041	0.053	0.071	0.094	0.118	0.147	0.178	0.212
SAARC	[€/kWh]	0.073	0.093	0.118	0.141	0.165	0.191	0.222	0.250
NE-Asia	[€/kWh]	0.072	0.090	0.094	0.098	0.103	0.107	0.112	0.117
SE-Asia	[€/kWh]	0.064	0.081	0.101	0.126	0.149	0.173	0.199	0.227
N-Am	[€/kWh]	0.082	0.102	0.125	0.150	0.173	0.199	0.229	0.256
S-Am	[€/kWh]	0.093	0.116	0.137	0.161	0.188	0.218	0.240	0.259

Table S8. Comparison of cumulative pathway cost by scenario at the end of the transition time horizon (%); The ‘+’ sign shows higher cost, and ‘-’ sign stands for lower cost. Every scenario in each row is compared with the corresponding scenarios in the columns.

		LUT-BPS					Teske/DLR		IEA	
		NWF	WF	Plus2040	Plus2035	Plus2030	2.0°C	1.5°C	SDS	STEPS
LUT-BPS	NWF		0.3%	-4.1%	-2.7%	-4.1%	32.7%	30.5%	25.9%	21.6%
	WF			-4.3%	-3.0%	-4.4%	32.4%	30.1%	25.6%	21.3%
	Plus2040				1.4%	-0.1%	38.3%	36.0%	31.3%	26.8%
	Plus2035					-1.5%	36.4%	34.1%	29.5%	25.0%
	Plus2030						38.4%	36.1%	31.4%	26.9%
Teske/DLR	2.0°C							-1.7%	-5.1%	-8.4%
	1.5°C								-3.5%	-6.8%
IEA	SDS									-3.4%
	STEPS									

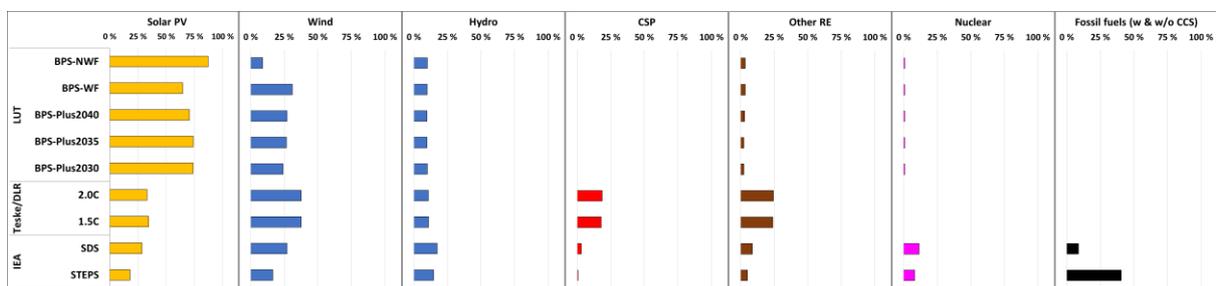


Figure S8. Contribution of various electricity generation technologies to cover the total electricity demand by scenarios in 2050. Other RE includes geothermal energy, bioenergy, ocean energy and renewable gas plus hydrogen.

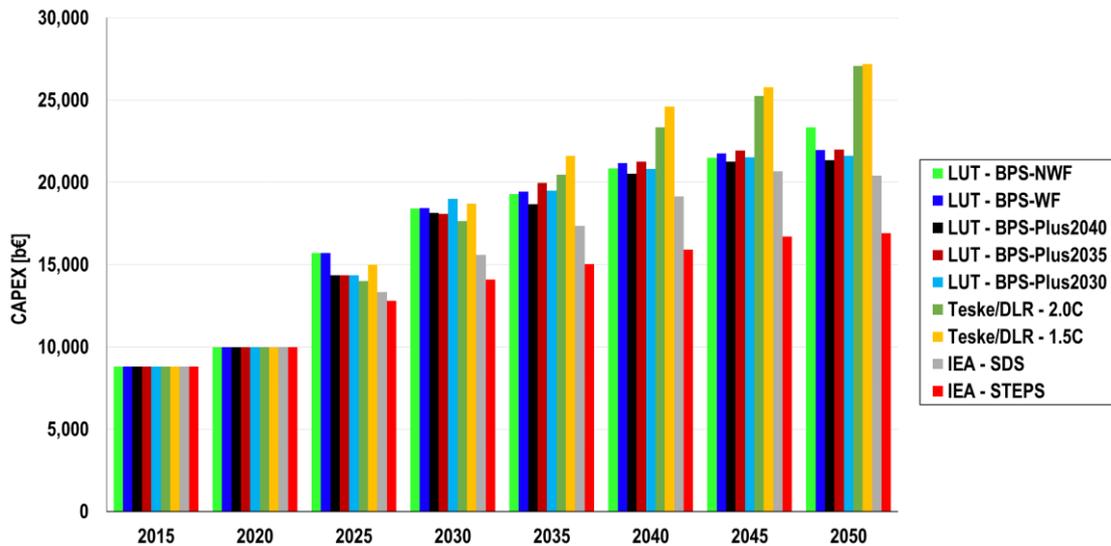


Figure S9. Development of capital expenditures in five-year intervals for the scenarios during the energy transition from 2015 to 2050. Displayed are the cumulative capex of the running system.

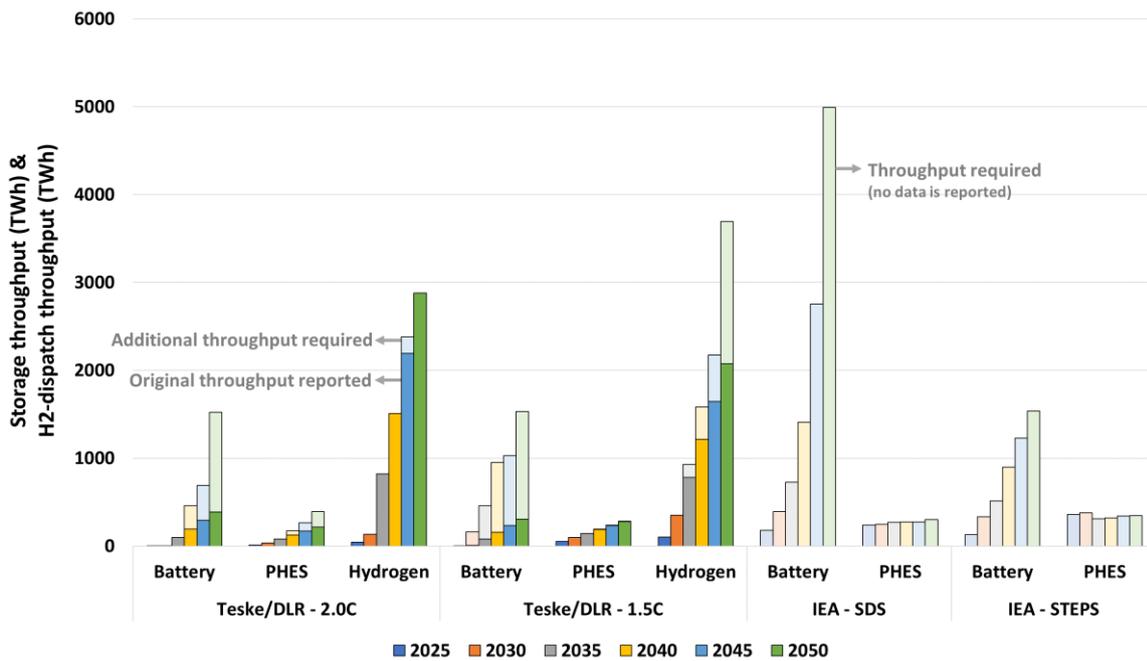


Figure S10. Reported and additional energy storage throughput for batteries and PHES plus hydrogen dispatch throughput in the Teske/DLR scenarios for the transition time horizon. Storage throughput is not documented in the IEA report, thus the model is allowed to generate the required throughput to balance the system.

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